UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, et al.	)	Docket Nos. ER03-563-000, ER03-563-030 and ER03-563-055

COMMENTS OF THE MAINE PUBLIC UTILITIES COMMISSION AND THE MAINE PUBLIC ADVOCATE IN REPLY TO COMMENTS SUPPORTING THE PROPOSED SETTLEMENT

Pursuant to Rule 602(f) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] the State of Maine Public Utilities Commission ("MPUC") and the Maine Office of the Public Advocate ("MOPA") hereby submit these reply comments, with the Supplemental Affidavit of Dr. Thomas D. Austin attached, in response to settlement comments filed by certain parties in the above-captioned proceeding on March 27, 2006. The limited comments submitted in support of the proposed settlement fail to provide the substantial evidence necessary to make a reasoned decision; nor do the comments resolve the genuine issues of material fact that exist.

In these reply comments, the MPUC and MOPA respond primarily to arguments made by the Connecticut Department of Public Utility Control with certain other parties from Connecticut,[2] Vermont, New Hampshire and Rhode Island that support the proposed settlement (collectively, "CTDPUC").[3] The CTDPUC comments rely on irrelevant ISO New England ("ISO-NE" or "ISO") exhibits to assert that Maine is not export constrained; make inappropriate

1 18 C.F.R. § 385.602(f) (2005).

2 This group does not include the Connecticut Attorney General, who filed comments opposing the proposed settlement.

3 The CTDPUC group style themselves the so-called "Load Supporters."

comparisons to the current ICAP market, which has no locational component; make irrelevant comparisons to rates that the Commission never approved and are not the likely result of litigation; and disregard locationality and reliance on market dynamics in favor of administrative fiat for determining whether price separation should occur. In addition, these reply comments briefly respond to PPL Parties' request to consider modifications to the energy markets, which is beyond the scope of the issues currently before the Commission, and the claim by the Reading Municipal Light Department ("Reading") that approval of the settlement is appropriate simply because it represents a compromise, which is inconsistent with the applicable standard of review.

Since there has been nothing offered in the comments to establish a record of substantial evidence upon which the Commission can make a reasoned decision and resolve the genuine issues of material fact, the MPUC and MOPA herein reiterate that FERC may approve the settlement agreement only if it conditions such acceptance on the settlement being modified to adopt: (1) a $2.00 per kW-month interim rate for the Maine zone during the transitional period;[4] (2) in the Forward Capacity Market ("FCM"), an auction-based determination as to whether the constraints for an import-constrained zone are binding; and (3) in the FCM, for the Maine zone, a Cost of New Entry ("CONE") of $6.50 per kW-month. Alternatively, the disputed issues described in the comments filed by the MPUC and MOPA in this proceeding on March 27, 2006, should be severed and set for hearing, or the settlement should be rejected in its entirety and the matter set for hearing.

A fair and equitable resolution of these issues, with due consideration for Maine's rather unique situation and needs, is particularly critical at this time. The Maine Legislature appears poised to enact legislation that requires the MPUC to consider whether Maine has good

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[4] All loads in Maine would pay this price.

alternatives to continued participation in the ISO-NE/NEPOOL structure. A major reason for that legislation is resentment over the fact that the proposed settlement denies Maine the benefits it should receive from generation located in the State. Moreover, the settlement's treatment of Maine has reinforced a pre-existing concern that as a state comprising only about 10 percent of New England load, Maine will always be subject to the tyranny of the majority, especially if FERC takes an "end justifies the means" position and is unwilling to protect the legitimate interests of small states.

II Reply Comments

A. ISO exhibits that model the export constraints in a LICAP context are not relevant in determining whether Maine's export constraint would bind in an auction.

CTDPUC asserts that there is no justification for a Maine-only price because the Maine export constraint does not bind. Specifically, CTDPUC states:[5]

> If transmission constraints out of Maine were binding, LICAP's locational pricing model would produce a lower price for capacity resources in the Maine zone than in the Rest of Pool zone, but Exhibit ISO-24 calculates six years of clearing prices using 11 different demand curves, with four different sensitivity analyses (Case 1-Case 4), and in all 264 cases, prices in Maine are the same as prices in Rest of Pool (or deviate not more than $0.03). ISO's updated price projections also show the same capacity prices for Maine and Rest of Pool.

Exhibit No. ISO-24 and the LaPlante affidavit, which is premised on the findings in that exhibit, are not relevant to the determination of whether in a locational capacity *auction* Maine's export constraints would bind so as to result in price separation. The model analyzed the effects of the administratively-determined LICAP demand curve, and thus imparts no information about what might occur under the FCM auction. Comparing the LICAP method to the FCM auction

5 CTDPUC Initial Comments at 44 (citations omitted).

mechanism is an apples-to-oranges comparison. A more valuable comparison would be to the energy market results. As stated in Dr. Austin's original and supplemental affidavits, export constraints commonly do, in fact, bind in the energy market, resulting in price separation in Maine.[6] Specifically, the negative congestion experienced in Maine is reflected in the congestion component of Maine's Locational Marginal Prices ("LMPs"). Because additional energy from Maine cannot be delivered to the rest of New England when the export constraint binds, the LMPs in the Maine zone are consistently depressed.

Because Exhibit No. ISO-24 and the LaPlante Affidavit consider whether constraints will bind under a demand curve, not an auction scenario, these exhibits are irrelevant to determining whether Maine is export constrained. They provide no sound basis to justify the absence of price separation between Maine and the rest of New England, especially when it is clear from the energy market that export constraints *do* bind and result in lower energy prices in Maine.[7]

Further, even under a LICAP scenario which, as discussed above is inappropriate for determining whether Maine is export constrained, the results reached by Exhibit No. ISO-24 and the LaPlante Affidavit are contradicted in a study completed in December 2005, entitled "Avoided Energy Costs For New England," prepared for the Avoided Energy Supply Component Study Group, a group of New England regulators and utilities formed to study the energy supply costs potentially avoided through the implementation of energy efficiency

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6 Austin Affidavit at PP 8-9; Austin Supplemental Affidavit at PP 5, 8.

7 *Id. See also, e.g.*, ISO-NE 2005 Third Quarter Markets Report ("Export constraints and negative marginal losses resulted in the Maine load zone having the lowest average prices.") (http://www.isone.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2005/2005_q3_quaterly_reports.pdf) at 18.

programs in New England. The study projected capacity prices under LICAP to be in the following approximate ranges for the six New England states for the period 2006-2010:[8]

State	Projected Capacity Price 2006-2010 (in dollars per kW-Year)
Maine	20-28
New Hampshire	35-67
Vermont	35-70
Rhode Island	35-70
Massachusetts	35-70
Connecticut	48-72

These results clearly show price separation between Maine and the rest of pool for the transition period, through 2010. Thus, even if a comparison to LICAP were appropriate, which it is not, the evidence shows that there should be price separation between Maine and the rest of New England.[9]

B. The Transition Payments Cannot Be Found To Be Just and Reasonable Based On A Comparison Of What The Rates Might Have Been Had The Status Quo Continued.

The CTDPUC asserts that the transition prices are reasonable because if the status quo continued, the ICAP price might reach the level of the transition payments or the existing cap of

[8] Avoided Energy Costs For New England, Exhibit No. A2-3 (Electric Energy Avoided Cost by State) at 176-181 (http://publicservice.vermont.gov/pub/other/aescfullreport2005.doc), attached hereto as Appendix A.

[9] CTDPUC also suggests that a transmission upgrade that will increase transmission capacity over the Maine-NH interface by 100 MW proves that Maine is not export constrained. As discussed in Dr. Austin's supplemental affidavit, this small increase may well be offset by an increase in Maine-based generation, particularly new wind and biomass resource. Supplemental Austin Affidavit at P 10.

$6.66 per kW month. It states:

> Although the proposed transition prices are higher than current ICAP prices, they are less than that market's price cap of $6.66 kW-month. As existing surpluses decline, even the ICAP market could clear prices near the agreed Settlement levels or even as high as the deficiency charge. Thus, even if the Commission did nothing and permitted continuation of the status quo, prices similar to the transition prices would be likely.

This argument is pure conjecture; CTDPUC provides no basis upon which to reasonably conclude that the market price will reach transition payment levels or hit the price cap.

Moreover, a comparison to the non-locational status quo is inappropriate because as Chairman Kelliher stated in oral argument, the status quo is not an option:[10]

> There's a problem in New England's wholesale power markets that cannot be ignored, namely, the collapse of generation additions and the threat that poses to reliability and just and reasonable wholesale power prices in New England. In particular, very little new generation is being added in Southwest Connecticut and Northeast Massachusetts. At the same time, demand continues, inexorably, to grow.
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> * * *
>
> The Commission is convinced there is a problem in wholesale power markets under the status quo.

This statement, viewed in the context of findings in ISO New England's Regional System Plan for 2005 ("RSP-05") that "[t]he largest concentrations of load are in the region's urban centers, Greater Boston, Southwest Connecticut, and the mid-Connecticut River Valley"[11] makes it clear

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10 Oral Argument Transcript (September 20, 2005) at page 2, line nos. 18-25 and page 3, line no. 1.

11 *See* RSP-05 at 5. *See also* RSP-05 at 12, which makes the following findings:

> The geographic distribution of New England's peak load in summer and winter is approximately 20 percent in the north (Maine, New Hampshire, and Vermont), and 80 percent in the south (Massachusetts, Connecticut, and Rhode Island). Although the northern area is larger geographically than the southern area, the larger southern load reflects greater development and the concentration of population in urban areas.

that "one size fits all" pricing which fails to value capacity by location is no longer an option for New England's resource adequacy mechanism.[12]

Rather than comparing the transition period payments to the current arrangement, which has no locational component, the proper comparison would be to the current vertical demand curve in a *locational* ICAP market. Under such a comparison, it is highly unlikely that Maine's price would rise to the level of the proposed transition payments because Maine's surplus is not likely to disappear during the transition period. Maine's projected increase in summer peak load is only 1.5 percent a year[13] and, as noted in Dr. Austin's Affidavit and Supplemental Affidavit, there are a number of wind generation and biomass projects proposed to be sited in Maine that are in various stages of planning and development.[14]

C. The Transition Payments Cannot Be Found to Be Just and Reasonable Based On A Comparison Of What The Rates Might Have Been Had The Commission Adopted the Initial Decision.

Relying on the standard dubbed "Approach No. 2" in *Trailblazer Pipeline Company,*[15] CTDPUC suggests that the proposed settlement is just and reasonable simply because it results in lower rates than those that may have applied if the Commission had adopted the Initial Decision without qualification or modification. Under Approach No. 2, the Commission may

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12 *See* Comments of PSEG Energy Resources and Trade LLC at 12 ("the proposed transitional market will not account for the locational value of generation for approximately five years from the present day - at the earliest").

13 Summer peak load is expected to increase at the rate of 1.7 percent annually for Connecticut and 1.9 percent annually for New Hampshire. *See* RSP-05 at 24.

14 If anything the comparison made by CTDPUC demonstrates that there is an unresolved issue of material fact about what Maine's payments would be under the current ICAP market. Whether the current rates will rise, and if so, by how much, cannot be determined on the existing record.

15 *Trailblazer Pipeline Co.*, 85 FERC ¶ 61,345 (1998) ("*Trailblazer I*"), *on reh'g*, 87 FERC ¶ 61,110 (1999) ("*Trailblazer II*").

approve a settlement if it finds "that the overall result of the settlement is just and reasonable."[16] One way to reach that conclusion is by finding that the settlement rates are lower than "the rates the contesting party was likely to pay if the case were litigated."[17]

Contrary to CTDPUC's position, nothing in *Trailblazer*, or the precedent cited therein,[18] suggests that an Initial Decision, never reviewed by the Commission and ultimately set aside in favor of the FCM, should be deemed the likely outcome of litigation. The Commission regularly rejects or modifies findings and conclusions made in initial decisions.[19] In this case, the flaws inherent in the Initial Decision were of such significance that it spawned legislation by Congress suggesting that FERC consider alternatives. Indeed, if CTDPUC's interpretation of the standard were correct, parties filing rate cases would be encouraged to consider proposing exceedingly high rates with the hope that a settlement could be reached that some parties would find acceptable and that contesting parties would be forced to accept merely because the rates were lower than rates that were skewed high from the start. The Commission should not countenance such a strategy by interpreting the standard as CTDPUC would have it do.

Furthermore, there are critical distinctions in the cases upon which CTDPUC relies. In *Indicated Shippers v. Sea Robin*,[20] the Commission found that the parties had raised genuine issues of material fact, but because the parties agreed that the record contained substantial evidence upon which to make a merits determination, the Commission proceeded to determine

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16 *Trailblazer I* at 62,342.

17 *Trailblazer II* at 61,440.

18 *Id.*

19 *See, e.g., Town of Norwood, Massachusetts v. National Grid USA, et al.*, 112 FERC ¶ 61,099 (2005); *Louisville Gas & Elec. Co., et al.*, 113 FERC ¶ 63,022 at P 81 (2005).

20 79 FRC ¶ 61,072 (1997), *on reh'g*, 81 FERC ¶ 61,146 (1997), *on reh'g*, 82 FERC ¶ 61,217 (1998).

the issues on the merits. Here, the MPUC and MOPA, as well as other parties, have raised issues of material fact and demonstrated that the record does not contain substantial evidence upon which to resolve them. In particular, genuine issues of material fact have been raised regarding the transition payments.

Also, in *Sea Robin,* the Commission actually engaged in the thorough analysis necessary to identify the likely outcome of litigation and found that certain aspects of the cost of service should have been determined differently than done in the settlement. Similarly, in *PG&E Gas Transmission, Northwest Corp.*,[21] the Commission engaged in a thorough analysis of the likely litigated outcome. CTDPUC does not suggest that the Commission undertake such a lengthy merits analysis; rather it suggests that the Commission simply assume that the Initial Decision would be the litigated result without making any merits determinations. The precedent does not support such a short cut.

As stated in the initial comments filed by the MPUC and MOPA, ISO and many others have embraced the FCM as a reasonable alternative to LICAP. What would be the likely litigated outcome in this case, therefore, is entirely uncertain. Most likely, the litigated outcome would be to adopt something very similar to the FCM as the long-term capacity market mechanism, and for the short-term some alternative payment arrangement more closely related to the ultimate market-based mechanism that is being adopted. One possible result for the short-term would be a locational UCAP with the option of RMR contracts for those entities not receiving sufficient compensation from energy and ancillary markets (including the existing UCAP market).

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21 76 FERC ¶ 61,246 (1996), *on reh'g*, 82 FERC ¶ 61,289 (1998).

Litigation would not likely result in the adoption of a demand curve for the short-term. The purpose of providing additional revenues during times of surplus under the demand curve is not to encourage investors to build at those times, but to provide assurance that some revenues will continue to be available even under surplus conditions.[22] Here, as CTDPUC acknowledges, there is no claim that the transition payments will result in investment in new generation.[23] Since there is currently excess capacity on the system, capacity payments should reflect the limited value of capacity during the transition.[24]

Moreover, even under a LICAP scenario, Maine has provided evidence that its payments should be reduced because it has surplus generation that cannot be delivered when there is a binding export constraint. For example, Exhibit No. MV-13 entered into evidence during the hearing, shows that Maine's LMP is consistently lower than the Hub or any other New England LMP zone. Thus, one of the litigated results that must be considered, under any scenario, LICAP or otherwise, is that Maine's resource adequacy prices actually reflect the reduced value of capacity in the Maine zone in comparison to other zones.

D. The CTDPUC Provides No Reasonable Explanation For The FCM's Failure To Allow The Auction to Determine Price Separation Between Zones

While the CTDPUC uses terms like "rigid" to describe an auction mechanism that allows the bidding process to determine whether constraints will bind in the auction, in fact, the opposite is true.[25] An administrative pre-determination that transmission constraints will or will not bind in import constrained zones, and the resulting lack of price separation if the pre-

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22 Hearing Transcript (February 24, 2005) at 569-570.

23 CTDPUC Initial Comments at 36.

24 *Id.* at 38.

25 *Id.* at 26.

determination is that they will not bind, is by its very nature inflexible.[26] Markets adapt to changing conditions, constantly seeking efficient solutions. The pre-determined conclusion that constraints do or do not bind suppresses market forces, ignoring changing conditions.

Further, CTDPUC rationalizes that the mechanism in the proposed settlement will "*identify* price separation between zones and send effective signals to build generation where needed."[27] This may be true, but *identification* of price separation was not what the Commission expected of a mechanism. The Commission envisioned that the mechanism would actually allow the *market* to price capacity by its locational value.[28] The proposed mechanism does not accomplish that objective for import constrained zones, unless price separation is permitted by an administrative pre-determination prior to the auction.[29]

Finally, CTDPUC fails to demonstrate that harm would arise from identifying separate zones and allowing the auction to determine if transmission constraints bind. If they do not bind, there would not be price separation; if they do, they are properly reflecting the interaction between the bidding patterns and the physical limits of the transmission system.[30]

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26 The ISO's Regional System Plan makes clear that projections about needs within the load pockets are subject to "uncertainties that could change the projected needs. The major uncertainties relate to load forecasts, ties benefits, transmission-upgrade schedules, transmission-transfer limits between load pockets, and retirement of existing generators." *See* RSP-05 at 113.

27 CTDPUC Initial Comments at 5 (emphasis added).

28 *Devon Power LLC, et al.*, 110 FERC ¶ 61,315 at P 15 (2005) (order on rehearing and clarification).

29 The proposed settlement envisions different treatment for import and export constrained zones. While a predetermination is made for import-constrained zones that will or will not permit price separation in the auction, export constraints are modeled in the auction. *See* Settlement Agreement, Section III.A.5.

30 *See, e.g., Devon,* 109 FERC ¶ 61,154 at P 12. (finding that the classification of a region as a LICAP region will not necessarily result in higher prices for that region as compared to the rest of pool region; if there is sufficient transmission import capacity into that region, there should be minimal price differentials between that region and the rest of pool region).

E. Other Arguments Similarly Fail To Provide Any Basis For Accepting The Proposed Settlement.

PPL Parties suggest that the Commission should initiate a proceeding to consider changes to the energy market in New England.[31] This request is clearly beyond the scope of the capacity issues before the Commission at this time. The proper approach for seeking market changes is through the stakeholder process and/or a filing pursuant to Section 206 of the Federal Power Act. PPL Parties' attempt to inject this issue into the discussion should be rejected.

Reading Municipal Light Department suggests, contrary to applicable standards, that the Commission should approve the settlement simply because it reflects a compromise.[32] Since settlements always reflect some level of compromise, Reading's redefined standard would reduce FERC's role to that of a rubber stamp, contrary to the Federal Power Act. The courts and the Commission have established the applicable standards for contested settlements to ensure just and reasonable results. Those standards should be upheld and applied in this instance.

III. CONCLUSION

WHEREFORE, the Maine Public Utilities Commission and the Maine Office of the Public Advocate hereby request that the settlement agreement not be certified and accepted as proposed, but rather, that acceptance be conditioned on modifying the settlement to adopt: (1) a $2.00 per-kW month interim rate for the Maine zone during the transitional period;[33] (2) in the FCM, an auction-based determination as to whether the constraints for an import-constrained zone are binding; and (3) in the FCM, for the Maine zone, a CONE of $6.50 per kW-month. Alternatively, the issues identified in the comments submitted by the Maine Public Utilities

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31 PPL Parties Initial Comments at 5-7.

32 Reading Initial Comments at 1-2.

33 All loads in Maine would pay this price.

Commission and the Maine Office of the Public Advocate on March 27 and herein should be severed and set for hearing in order to establish a record upon which a reasoned decision can be reached.

Respectfully submitted,

/s/ Stephen G. Ward

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Dated: April 5, 2006

CERTIFICATE OF SERVICE

In accordance with Rule 2010 of FERC's Rules of Practice and Procedure,[34] I hereby certify that I have served a copy of the foregoing upon those parties listed on the official service list prepared by the Secretary of the Commission in this proceeding.

Dated at Washington, D.C.,
this 5th day of April

/s/ John R. Matson, III

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[34] 18 C.F.R. § 385.2010 (2005).

SUPPLEMENTAL AFFIDAVIT OF THOMAS D. AUSTIN

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, et al.	)	Docket Nos. ER03-563-000, ER03-563-030 and ER03-563-055

STATE OF MAINE) ss

County of ______________

SUPPLEMENTAL AFFIDAVIT OF THOMAS D. AUSTIN

Introduction

1. My name is Thomas D. Austin. I am employed as an economist for the Maine Public Utilities Commission, 242 State St., Station 18, Augusta, ME, 04333. My qualifications are listed in the testimony that I previously filed in this docket (Exhibit MV-1).

2. On March 27, 2006, I submitted an affidavit in this case ("March 27 Affidavit"), which accompanied the comments filed by the Maine Public Utilities Commission ("MPUC") and the Maine Office of the Public Advocate ("MOPA"). My March 27 Affidavit identified the lack of substantial evidence and existence of genuine issues of material fact in this case. It also explained the importance of including locational considerations in both the transition and long term markets and pointed out that the transition payments for Maine were unreasonably high. This affidavit, which is intended to respond to the comments submitted in this proceeding, supplements my March 27 Affidavit.

3. The "Load Supporters" filed comments in support of the contested settlement on March 27, 2006, stating, among other things, that it was appropriate to have the same price for capacity in Maine as in the other portions of New England during the transition period. More specifically, they state that "... not only is there no economic theory to support location-based prices during the temporary transition period, but no record evidence supports such differentials." (Load Supporters at p. 45.)

4. First, I must note that to the best of my knowledge, there is no record evidence supporting any aspect of the transition period capacity payments, other than the Affidavits of Messrs. LaPlante and Stoddard, which, as I addressed in my March 27 Affidavit, and the MPUC and MOPA pointed out in their comments, do not provide the substantial evidence upon which a reasoned decision can be made and the genuine issues of material fact can be resolved.

5. In my view, the primary goal of the transition payment is to provide a fair payment to generators and a fair allocation of the costs of those payments to load. As I pointed out in my March 27 Affidavit, the only data on the likelihood and level of constraints in New England is the historical levels of congestion in the energy market. The most recent available evidence here is for 2005 when Maine was export constrained for the vast majority of summer on peak hours. This suggests that additional capacity in Maine would have been unable to improve reliability in some or all of the rest of New England. My March 27 Affidavit also pointed out that congestion between Maine and New Hampshire was also common during summer peak hours.

6. If there is an export constraint in the energy market at a particular time and place, this tells us that additional capacity at that location will be unable to deliver additional

energy, and therefore additional reliability, to one or more areas elsewhere in New England. Exactly which areas are unreachable will vary. For example, in one congested hour, the Maine-New Hampshire interface might be congested and Maine generation would be unable to get out of Maine. In another hour, The North-South (New Hampshire-Massachusetts) interface might be constrained and Maine generation could get into New Hampshire, but no further. At the opposite extreme, there might be a third hour when a constraint in Southwest Connecticut ("SWCT") results in Maine Generation reaching all of New England but SWCT.

The most important thing to note is that when there are constraints in the Real Time Energy Market, Maine generation cannot support the reliability needs of some or all of New England.

7. These comments can also be applied to generators located elsewhere in New England. For example, when there is energy congestion at a particular location, for example central Massachusetts, a generator at that location would also be unable to support the reliability needs of some areas of New England. It is really a question of degree. The constraints in the energy market have been significantly greater for Maine locations than for other locations in New England.

8. My March 27 Affidavit partially addressed this issue by considering the likelihood of greater congestion levels in Maine, as opposed to New Hampshire. There, I showed that congestion in Maine was greater than New Hampshire in about half of the summer peak hours of 2005. In addition, the table below compares the level of congestion, by month, for Maine and the New England Hub in 2005. A negative value

indicates an export constraint, reducing the energy price. A positive value indicates the converse.

	Hub ($/MWh)	Real Time Congestion Maine ($/MWh)
January-05	0.02	-0.12
February-05	-0.17	0.07
March-05	-0.65	-0.80
April-05	-0.27	-1.43
May-05	-0.10	-3.30
June-05	-1.34	-3.63
July-05	-2.24	-4.03
August-05	-2.98	-6.84
September-05	-0.97	-4.16
October-05	-0.58	-2.06
November-05	-0.35	-0.59
December-05	-0.79	-0.90

Source: "Monthly Market Reports," Jan. 2005 through Dec. 2005, ISO-NE, http://www.iso-ne.com/markets/mkt_anlys_rpts/mnly_mktops_rtps/index.html

9. In the end, the level of the transition payments is largely a question of equity. In this case, the settlement attempts to achieve that equity by including a position that garners the support of a large group of signatories. The problem here is that most of the signatories (understandably) favored a solution that lowers their costs, which would be politically more palatable to their respective constituencies, but ignores Maine's unique position and needs. While there is a political explanation for the outcome of such a vote, that does not mean the result is just and reasonable.

10. The Load Supporters attempt to buttress their argument that Maine is not export constrained (Load Supporters at p. 45) by stating, "If any further confirmation were required, ISO's most recent Regional System Plan ("RSP-05") has identified

transmission upgrades that will increase transmission capacity [by 100 MW] over the Maine/Rest of Pool interface." This comment seriously misrepresents the thrust of that report.

I do not quarrel with the assertion that we may see a small increase in the transfer limit over the next few years. However, one must also recognize that there is a substantial possibility that there will also be an increase in Maine based generation, particularly from new wind, biomass, and demand-side resources, which could more than offset such a modest increase in the transfer limit.

More importantly, RSP-05 draws a clear picture of the locational need for resources during the transition period. Rather than trying to characterize this picture, I will simply quote two relevant passages from RSP-05.

> The New England transmission system may not be able to transfer to load the full output from all of New England generators. For example, Greater Connecticut is transmission limited, and power cannot always reliably or securely flow from a generator within that area to load there. Also, the Maine-New Hampshire interface limits receipt of generation output from Maine, including transfers from New Brunswick into New England. (RSP-05 Executive Summary at p. ES-5.)
>
> Figure 4.6 shows the results [of the Loss of Load Analysis] for 2010 when New England would be approximately 270 MW short of resources to meet the LOLE criterion. As shown, the criterion can be met in two ways - by decreasing 270 MW of load or increasing 270 MW of effective resources in the Connecticut subareas. A less effective alternative is to reduce approximately 950 MW of load or add 950 MW of capacity in subareas on the southern side of the North-South interface. Load reduction or resource addition in other New England subareas on the North side of the North South interface would not help meet the system LOLE criterion due to transmission import constraints into the CT subarea which is in need of resources. (RSP-05 at p. 45)

For clarity, I should reiterate that the North-South interface is, in essence, the interface between Massachusetts and New Hampshire and that Maine is on the

North side of the interface. In any event, the story ISO-NE tells in RSP-05 is quite clear. New England will need new capacity during the transition period. The best place for that new capacity would be in Connecticut. Capacity in other areas in Southern New England would help, but each MW of new resources in the that area produces only about 26% of the benefit of MW of new resources in Connecticut. The RSP-05 also clearly states that Maine is transmission constrained and that new capacity there (and in New Hampshire as well) would not contribute to reliability due to transmission constraints.

The Maine Zone does not need additional resources to meet reliability requirements. In response to the Load Supporters' assertion, I can only say that both economic theory and the available evidence provide clear support for a lower transition charge in Maine. Maine does not need new resources during this time frame and new resources built in Maine will not allow other parts of the region to achieve the required level of reliability.

Being first duly sworn, I declare that I have reviewed the foregoing in its entirety, and I further declare that it is true and accurate to the best of my knowledge, information and belief.

Thomas D. Austin.

Subscribed and sworn to before me this 5th day of April, 2006.

Notary Public

JENNIFER PAUL
NOTARY PUBLIC • MAINE
MY COMMISSION EXPIRES JUNE 21, 2007

My Commission Expires:
[SEAL]

APPENDIX A

Avoided Energy Supply Costs in New England

Prepared for:

Avoided-Energy-Supply-Component (AESC) Study Group

Prepared by:

ICF CONSULTING

Final Report

December 23, 2005

Exhibit A2-3. Electric Energy Avoided Costs by State

	Maine																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit, load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May, Sept-Dec	3-5 pm						
2005[1]	0.071	0.063	0.063	0.049	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.080	0.071	0.070	0.057	23.304	0.000	23.304	1.942	5.465	1.084	23.304	0.003	0.003	1,115.39	0.127	90.57	0.010
2007	0.083	0.072	0.072	0.059	20.172	0.000	20.172	1.681	4.730	0.938	20.172	0.002	0.002	616.86	0.070	43.53	0.005
2008	0.070	0.059	0.060	0.048	19.462	0.000	19.462	1.622	4.564	0.905	19.462	0.002	0.002	23.10	0.003	6.00	0.001
2009	0.056	0.047	0.048	0.039	17.895	0.000	17.895	1.491	4.196	0.832	17.895	0.002	0.002	6.57	0.001	4.86	0.001
2010	0.049	0.041	0.043	0.034	27.761	0.000	27.761	2.313	6.510	1.291	27.761	0.003	0.003	9.00	0.001	7.86	0.001
2011	0.051	0.043	0.046	0.036	43.067	0.000	43.067	3.589	10.099	2.003	43.067	0.005	0.005	11.43	0.001	10.86	0.001
2012	0.054	0.044	0.049	0.038	66.810	0.000	66.810	5.568	15.667	3.107	66.810	0.008	0.008	13.86	0.002	13.86	0.002
2013	0.054	0.045	0.049	0.039	67.163	0.000	67.163	5.597	15.750	3.123	67.163	0.008	0.008	13.76	0.002	13.02	0.001
2014	0.054	0.046	0.049	0.039	67.517	0.000	67.517	5.626	15.833	3.140	67.517	0.008	0.008	13.66	0.002	12.18	0.001
2015	0.055	0.046	0.049	0.039	67.872	0.000	67.872	5.656	15.916	3.156	67.872	0.008	0.008	13.56	0.002	11.34	0.001
2016	0.055	0.047	0.049	0.039	68.230	0.000	68.230	5.686	16.000	3.173	68.230	0.008	0.008	13.46	0.002	10.51	0.001
2017	0.057	0.048	0.051	0.041	65.767	0.000	65.767	5.481	15.422	3.058	65.767	0.008	0.008	12.91	0.001	10.69	0.001
2018	0.059	0.050	0.053	0.043	63.392	0.000	63.392	5.283	14.865	2.948	63.392	0.007	0.007	12.36	0.001	10.88	0.001
2019	0.061	0.052	0.055	0.045	61.103	0.000	61.103	5.092	14.329	2.841	61.103	0.007	0.007	11.80	0.001	11.07	0.001
2020	0.063	0.054	0.057	0.047	58.896	0.000	58.896	4.908	13.811	2.739	58.896	0.007	0.007	11.25	0.001	11.25	0.001
2021	0.064	0.054	0.058	0.048	60.454	0.000	60.454	5.038	14.177	2.811	60.454	0.007	0.007	16.72	0.002	7.79	0.001
2022	0.064	0.055	0.059	0.048	62.053	0.000	62.053	5.171	14.552	2.885	62.053	0.007	0.007	22.18	0.003	4.32	0.000
2023	0.065	0.055	0.060	0.049	63.695	0.000	63.695	5.308	14.936	2.962	63.695	0.007	0.007	27.65	0.003	0.88	0.000
2024	0.065	0.056	0.061	0.050	65.380	0.000	65.380	5.448	15.332	3.040	65.380	0.007	0.007	33.12	0.004	[illegible]	[illegible]
2025	0.066	0.056	0.061	0.051	67.109	0.000	67.109	5.592	15.737	3.121	67.109	0.008	0.008	38.58	0.004	[illegible]	[illegible]
2026	0.067	0.057	0.062	0.051	68.885	0.000	68.885	5.740	16.153	3.203	68.885	0.008	0.008	44.05	0.005	[illegible]	[illegible]
2027	0.067	0.057	0.063	0.052	70.707	0.000	70.707	5.892	16.581	3.288	70.707	0.008	0.008	49.51	0.006	[illegible]	[illegible]
2028	0.068	0.058	0.064	0.053	72.577	0.000	72.577	6.048	17.019	3.375	72.577	0.008	0.008	54.98	0.006	[illegible]	[illegible]
2029	0.069	0.058	0.065	0.054	74.497	0.000	74.497	6.208	17.470	3.464	74.497	0.009	0.009	60.45	0.007	[illegible]	[illegible]
2030	0.069	0.059	0.066	0.054	76.468	0.000	76.468	6.372	17.932	3.556	76.468	0.009	0.009	65.91	0.008	[illegible]	[illegible]
2031	0.069	0.059	0.066	0.054	70.863	0.000	70.863	5.905	16.617	3.295	70.863	0.008	0.008	61.90	0.007	[illegible]	[illegible]
2032	0.070	0.059	0.066	0.054	65.669	0.000	65.669	5.472	15.399	3.054	65.669	0.007	0.007	57.88	0.007	[illegible]	[illegible]
2033	0.070	0.059	0.067	0.054	60.856	0.000	60.856	5.071	14.271	2.830	60.856	0.007	0.007	53.87	0.006	[illegible]	[illegible]
2034	0.070	0.059	0.067	0.054	56.395	0.000	56.395	4.700	13.225	2.622	56.395	0.006	0.006	49.85	0.006	[illegible]	[illegible]
2035	0.070	0.059	0.067	0.054	52.262	0.000	52.262	4.355	12.255	2.430	52.262	0.006	0.006	45.84	0.005	[illegible]	[illegible]
2036	0.070	0.059	0.068	0.054	48.431	0.000	48.431	4.036	11.357	2.252	48.431	0.006	0.006	41.82	0.005	[illegible]	[illegible]
2037	0.070	0.059	0.068	0.054	44.881	0.000	44.881	3.740	10.525	2.087	44.881	0.005	0.005	37.81	0.004	[illegible]	[illegible]
2038	0.070	0.059	0.068	0.054	41.591	0.000	41.591	3.466	9.753	1.934	41.591	0.005	0.005	33.79	0.004	[illegible]	[illegible]
2039	0.070	0.059	0.068	0.054	38.543	0.000	38.543	3.212	9.038	1.792	38.543	0.004	0.004	29.78	0.003	[illegible]	[illegible]
2040	0.070	0.059	0.069	0.053	35.718	0.000	35.718	2.976	8.376	1.661	35.718	0.004	0.004	25.76	0.003	6.15	0.001
Levelized[2]:																	
2005-2040	0.064	0.055	0.059	0.047	51.998	0.000	51.998	4.333	12.194	2.418	51.998	0.006	0.006	90.231	0.010	4.165	0.000
2006-2040	0.064	0.054	0.059	0.047	54.088	0.000	54.088	4.507	12.684	2.515	54.088	0.006	0.006	93.858	0.011	4.333	0.000
2006-2010	0.068	0.058	0.059	0.047	21.693	0.000	21.693	1.808	5.087	1.009	21.693	0.002	0.002	365.592	0.042	31.390	0.004
2006-2015	0.061	0.052	0.054	0.043	40.959	0.000	40.959	3.414	9.607	1.905	40.969	0.005	0.005	198.259	0.023	22.304	0.003
2006-2020	0.061	0.051	0.054	0.043	47.760	0.000	47.760	3.980	11.200	2.221	47.760	0.005	0.005	142.410	0.016	18.869	0.002

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

Massachusetts

	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value of Load Response (at any month)
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month
Comment 1.	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level
Comment 2					info	info	June/July/August	Average for 1 month savings
Period:							3-5 pm	
2005[2]	0.074	0.064	0.069	0.051	3.508	2.728	6.637	0.326
2006	0.085	0.072	0.077	0.059	34.873	6.047	40.920	2.906
2007	0.087	0.074	0.081	0.062	39.500	5.576	45.076	3.292
2008	0.074	0.060	0.072	0.050	63.019	0.108	63.127	5.252
2009	0.060	0.049	0.056	0.040	67.385	0.111	67.496	5.615
2010	0.052	0.042	0.049	0.035	70.352	0.096	70.447	5.863
2011	0.055	0.044	0.051	0.037	73.448	0.083	73.531	6.121
2012	0.057	0.046	0.052	0.038	76.681	0.072	76.753	6.390
2013	0.057	0.046	0.053	0.039	77.672	0.000	77.672	6.473
2014	0.058	0.046	0.054	0.039	78.675	0.000	78.675	6.556
2015	0.058	0.047	0.054	0.040	79.691	0.000	79.691	6.641
2016	0.059	0.047	0.055	0.040	80.721	0.000	80.721	6.727
2017	0.060	0.049	0.057	0.042	80.070	0.000	80.070	6.672
2018	0.062	0.051	0.059	0.044	79.424	0.000	79.424	6.619
2019	0.064	0.053	0.061	0.045	78.783	0.000	78.783	6.565
2020	0.066	0.055	0.064	0.047	78.148	0.000	78.148	6.512
2021	0.066	0.055	0.065	0.048	78.286	0.000	78.286	6.524
2022	0.067	0.056	0.065	0.049	78.425	0.000	78.425	6.535
2023	0.068	0.056	0.066	0.049	78.564	0.000	78.564	6.547
2024	0.068	0.057	0.067	0.050	78.703	0.000	78.703	6.559
2025	0.069	0.057	0.068	0.051	78.842	0.000	78.842	6.570
2026	0.070	0.058	0.069	0.051	78.981	0.000	78.981	6.582
2027	0.070	0.059	0.069	0.052	79.121	0.000	79.121	6.593
2028	0.071	0.059	0.070	0.053	79.261	0.000	79.261	6.605
2029	0.072	0.060	0.071	0.054	79.402	0.000	79.402	6.617
2030	0.072	0.060	0.072	0.054	79.542	0.000	79.542	6.629
2031	0.072	0.060	0.072	0.054	73.643	0.000	73.643	6.137
2032	0.072	0.060	0.073	0.054	68.182	0.000	68.182	5.682
2033	0.072	0.060	0.073	0.054	63.126	0.000	63.126	5.260
2034	0.072	0.060	0.074	0.054	58.444	0.000	58.444	4.870
2035	0.072	0.059	0.074	0.053	54.110	0.000	54.110	4.509
2036	0.072	0.059	0.074	0.053	50.097	0.000	50.097	4.175
2037	0.072	0.059	0.075	0.053	46.382	0.000	46.382	3.865
2038	0.072	0.059	0.075	0.053	42.942	0.000	42.942	3.579
2039	0.072	0.059	0.076	0.053	39.758	0.000	39.758	3.313
2040	0.072	0.059	0.076	0.053	36.809	0.000	36.809	3.067
Levelized[1]:								
2005-2040	0.067	0.056	0.065	0.048	66.167	0.558	66.725	5.514
2006-2040	0.067	0.055	0.065	0.048	68.669	0.471	69.139	5.722
2006-2010	0.072	0.060	0.067	0.050	54.628	2.458	57.085	4.552
2006-2015	0.065	0.053	0.060	0.044	65.330	1.306	66.641	5.445
2006-2020	0.064	0.052	0.060	0.044	69.578	0.913	70.491	5.798

	Avoidable Capacity Payment of Load Response (Summer Season)	Avoidable Capacity Payment of Load Response (Winter Season)	Avoidable Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1.	Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level		Avoided Cost applicable to KW savings at Summer Coincident Peak, load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:	June, July, August	Jan-May,Sept-Dec	3-5 pm						
2005[2]	0.917	0.182	6.637	0.000	0.001	0.00	0.000	0.00	0.000
2006	8.178	1.622	40.920	0.004	0.005	693.25	0.079	35.43	0.004
2007	9.263	1.837	45.076	0.005	0.005	939.61	0.107	73.18	0.008
2008	14.778	2.930	63.127	0.007	0.007	33.89	0.004	15.42	0.002
2009	15.802	3.133	67.496	0.008	0.008	393.57	0.045	24.38	0.003
2010	16.497	3.271	70.447	0.008	0.008	296.45	0.034	7.00	0.001
2011	17.224	3.415	73.531	0.008	0.008	199.34	0.023	[illegible]	[illegible]
2012	17.982	3.566	76.753	0.009	0.009	102.22	0.012	[illegible]	[illegible]
2013	18.214	3.612	77.672	0.009	0.009	129.83	0.015	[illegible]	[illegible]
2014	18.449	3.658	78.675	0.009	0.009	157.43	0.018	[illegible]	[illegible]
2015	18.689	3.706	79.691	0.009	0.009	185.04	0.021	2.74	0.000
2016	18.929	3.754	80.721	0.009	0.009	212.64	0.024	12.89	0.001
2017	18.776	3.723	80.070	0.009	0.009	240.57	0.027	15.16	0.002
2018	18.625	3.693	79.424	0.009	0.009	268.50	0.031	17.43	0.002
2019	18.475	3.663	78.783	0.009	0.009	296.43	0.034	19.70	0.002
2020	18.326	3.634	78.148	0.009	0.009	324.36	0.037	21.96	0.003
2021	18.350	3.640	78.286	0.009	0.009	304.56	0.035	18.04	0.002
2022	18.391	3.647	78.425	0.009	0.009	284.77	0.033	14.12	0.002
2023	18.423	3.653	78.564	0.009	0.009	264.97	0.030	10.20	0.001
2024	18.456	3.660	78.703	0.009	0.009	245.18	0.028	6.28	0.001
2025	18.488	3.666	78.842	0.009	0.009	225.38	0.026	2.36	0.000
2026	18.521	3.673	78.981	0.009	0.009	205.59	0.023	[illegible]	[illegible]
2027	18.554	3.679	79.121	0.009	0.009	185.79	0.021	[illegible]	[illegible]
2028	18.587	3.686	79.261	0.009	0.009	166.00	0.019	[illegible]	[illegible]
2029	18.620	3.692	79.402	0.009	0.009	146.21	0.017	[illegible]	[illegible]
2030	18.653	3.699	79.542	0.009	0.009	126.41	0.014	[illegible]	[illegible]
2031	17.269	3.424	73.643	0.008	0.008	116.05	0.013	[illegible]	[illegible]
2032	15.989	3.170	68.182	0.008	0.008	105.69	0.012	[illegible]	[illegible]
2033	14.803	2.935	63.126	0.007	0.007	95.33	0.011	[illegible]	[illegible]
2034	13.705	2.718	58.444	0.007	0.007	84.97	0.010	[illegible]	[illegible]
2035	12.689	2.516	54.110	0.006	0.006	74.61	0.009	[illegible]	[illegible]
2036	11.740	2.330	50.097	0.006	0.006	64.24	0.007	[illegible]	[illegible]
2037	10.877	2.157	46.382	0.005	0.005	53.88	0.006	[illegible]	[illegible]
2038	10.070	1.997	42.942	0.005	0.005	43.52	0.005	[illegible]	[illegible]
2039	9.323	1.849	39.758	0.005	0.005	33.10	0.004	[illegible]	[illegible]
2040	8.632	1.712	36.809	0.004	0.004	22.80	0.003	[illegible]	[illegible]
Levelized[1]:									
2005-2040	15.510	3.077	66.725	0.008	0.008	222.99	0.025	3.18	0.000
2006-2040	16.103	3.193	69.139	0.008	0.009	231.555	0.026	3.309	0.000
2006-2010	12.810	2.540	57.085	0.006	0.007	476.781	0.054	31.501	0.004
2006-2015	15.321	3.038	66.641	0.007	0.008	323.802	0.037	10.725	0.001
2006-2020	16.316	3.235	70.491	0.008	0.009	306.849	0.035	12.712	0.001

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

	New Hampshire																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May,Sept-Dec	3-5 pm						
2005[2]	0.072	0.063	0.066	0.049	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.082	0.070	0.074	0.058	34.548	1.801	36.350	2.870	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.085	0.072	0.079	0.060	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	906.91	0.104	88.60	0.010
2008	0.072	0.059	0.070	0.050	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.058	0.048	0.055	0.039	66.758	0.204	66.962	5.503	15.655	3.104	66.962	0.008	0.008	357.66	0.041	9.02	0.001
2010	0.051	0.041	0.048	0.034	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	(6.87)	(0.001)
2011	0.053	0.043	0.050	0.036	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.008	174.43	0.020	(23.35)	(0.003)
2012	0.056	0.045	0.051	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	(39.64)	(0.005)
2013	0.056	0.045	0.052	0.038	76.270	0.000	76.270	6.350	17.885	3.547	76.270	0.009	0.009	119.16	0.014	(21.08)	(0.002)
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	(2.33)	(0.000)
2015	0.057	0.046	0.053	0.039	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.047	0.054	0.039	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.059	0.048	0.056	0.041	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	30.72	0.004
2018	0.061	0.050	0.058	0.043	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.063	0.052	0.061	0.045	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.054	0.063	0.047	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.065	0.054	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.066	0.055	0.065	0.048	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.067	0.056	0.065	0.049	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.067	0.056	0.066	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.068	0.057	0.067	0.050	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.069	0.057	0.068	0.051	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	(0.65)	(0.000)
2028	0.070	0.058	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	(5.65)	(0.001)
2029	0.071	0.059	0.071	0.053	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	(12.64)	(0.001)
2030	0.072	0.060	0.071	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	(15.64)	(0.002)
2031	0.072	0.059	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	(16.43)	(0.002)
2032	0.072	0.059	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	(13.22)	(0.002)
2033	0.072	0.059	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.02	0.010	(13.01)	(0.002)
2034	0.072	0.059	0.073	0.053	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	(17.00)	(0.002)
2035	0.072	0.059	0.073	0.053	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	(17.50)	(0.002)
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	(17.38)	(0.002)
2037	0.072	0.058	0.074	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	(17.17)	(0.002)
2038	0.071	0.058	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	(16.96)	(0.002)
2039	0.071	0.058	0.075	0.052	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	(16.75)	(0.002)
2040	0.071	0.058	0.075	0.052	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.066	0.055	0.064	0.047	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.066	0.055	0.064	0.047	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.070	0.059	0.065	0.049	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	448.938	0.051	28.472	0.003
2006-2015	0.063	0.052	0.059	0.043	64.347	0.515	64.862	5.302	15.009	2.992	64.862	0.007	0.007	304.283	0.035	6.083	0.001
2006-2020	0.063	0.052	0.059	0.043	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

Rhode Island																	
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value	Annual Cost of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit, load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak, load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2.					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May,Sept-Dec	3-5 pm						
2005[1]	0.073	0.064	0.068	0.051	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.084	0.072	0.077	0.060	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.004	654.43	0.075	32.57	0.004
2007	0.087	0.074	0.081	0.062	39.132	2.151	41.283	3.261	9.176	1.820	41.283	0.004	0.005	908.91	0.104	88.60	0.010
2008	0.074	0.060	0.071	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.007	32.87	0.004	15.28	0.002
2009	0.060	0.049	0.056	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.008	357.68	0.041	9.62	0.001
2010	0.052	0.042	0.048	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.008	266.06	0.030	[illegible]	[illegible]
2011	0.054	0.044	0.050	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.009	174.43	0.020	[illegible]	[illegible]
2012	0.057	0.045	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.009	82.81	0.009	[illegible]	[illegible]
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.009	119.16	0.014	[illegible]	[illegible]
2014	0.057	0.046	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.009	155.52	0.018	[illegible]	[illegible]
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.009	191.87	0.022	16.43	0.002
2016	0.058	0.047	0.054	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.009	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.056	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.009	258.99	0.030	36.72	0.004
2018	0.062	0.050	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.009	289.75	0.033	38.26	0.004
2019	0.063	0.052	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.009	320.52	0.037	39.80	0.005
2020	0.065	0.054	0.063	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.009	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.064	0.048	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.009	328.09	0.037	35.34	0.004
2022	0.067	0.055	0.065	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.009	304.90	0.035	29.34	0.003
2023	0.067	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.009	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.050	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.009	258.50	0.030	17.35	0.002
2025	0.069	0.057	0.067	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.009	235.31	0.027	11.35	0.001
2026	0.069	0.058	0.068	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.009	212.11	0.024	5.35	0.001
2027	0.070	0.058	0.069	0.052	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.009	188.91	0.022	[illegible]	[illegible]
2028	0.071	0.059	0.070	0.053	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.009	165.72	0.019	[illegible]	[illegible]
2029	0.072	0.060	0.071	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.009	142.52	0.016	[illegible]	[illegible]
2030	0.072	0.060	0.072	0.054	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.009	119.32	0.014	[illegible]	[illegible]
2031	0.072	0.060	0.072	0.054	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.008	109.42	0.012	[illegible]	[illegible]
2032	0.072	0.060	0.072	0.054	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.008	99.52	0.011	[illegible]	[illegible]
2033	0.072	0.060	0.073	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.007	89.62	0.010	[illegible]	[illegible]
2034	0.072	0.060	0.073	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.007	79.72	0.009	[illegible]	[illegible]
2035	0.072	0.059	0.074	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.006	69.82	0.008	[illegible]	[illegible]
2036	0.072	0.059	0.074	0.053	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.006	59.92	0.007	[illegible]	[illegible]
2037	0.072	0.059	0.075	0.053	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.005	50.02	0.006	[illegible]	[illegible]
2038	0.072	0.059	0.075	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.005	40.12	0.005	[illegible]	[illegible]
2039	0.072	0.058	0.075	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.004	30.22	0.003	[illegible]	[illegible]
2040	0.072	0.058	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.004	20.32	0.002	[illegible]	[illegible]
Levelized[1]:																	
2005-2040	0.067	0.056	0.065	0.048	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.007	220.657	0.025	7.200	0.001
2006-2040	0.067	0.055	0.065	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.008	229.525	0.026	7.489	0.001
2006-2010	0.072	0.060	0.067	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.006	440.938	0.051	28.472	0.003
2006-2015	0.065	0.053	0.060	0.045	64.347	0.515	64.862	5.302	15.089	2.992	64.862	0.007	0.007	304.283	0.035	8.063	0.001
2006-2020	0.064	0.052	0.059	0.044	67.922	0.360	68.282	5.660	15.926	3.158	68.282	0.008	0.008	299.546	0.034	17.117	0.002

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

	Vermont																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value at Load Response (at any month)	Avoidable Capacity Payment at Load Response (Summer Season)	Avoidable Capacity Payment at Load Response (Winter Season)	Avoidable Capacity Payment at Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2:					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values are		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May; Sept-Dec	3-5 pm						
2005[2]	0.077	0.064	0.074	0.052	2.662	0.954	3.616	0.222	0.624	0.124	3.616	0.000	0.000	0.00	0.000	0.00	0.000
2006	0.088	0.072	0.081	0.061	34.548	1.801	36.350	2.879	8.102	1.607	36.350	0.004	0.001	654.43	0.075	32.57	0.004
2007	0.090	0.074	0.085	0.062	39.132	2.151	41.283	3.261	9.170	1.820	41.283	0.004	0.001	906.91	0.104	88.60	0.010
2008	0.070	0.060	0.073	0.051	62.436	0.199	62.635	5.203	14.641	2.903	62.635	0.007	0.002	32.87	0.004	15.28	0.002
2009	0.062	0.049	0.058	0.040	66.758	0.204	66.962	5.563	15.655	3.104	66.962	0.008	0.002	357.68	0.041	9.62	0.001
2010	0.053	0.042	0.050	0.035	69.696	0.177	69.874	5.808	16.344	3.241	69.874	0.008	0.002	266.00	0.030	(6.57)	(0.001)
2011	0.055	0.044	0.051	0.037	72.764	0.154	72.918	6.064	17.063	3.384	72.918	0.008	0.002	174.43	0.020	(23.35)	(0.003)
2012	0.056	0.046	0.052	0.038	75.967	0.133	76.100	6.331	17.814	3.532	76.100	0.009	0.002	82.81	0.009	(39.84)	(0.005)
2013	0.057	0.046	0.053	0.039	76.270	0.000	76.270	6.356	17.885	3.547	76.270	0.009	0.002	119.16	0.014	(21.05)	(0.002)
2014	0.057	0.047	0.053	0.039	76.575	0.000	76.575	6.381	17.957	3.561	76.575	0.009	0.002	155.52	0.018	(2.33)	(0.000)
2015	0.058	0.047	0.054	0.040	76.881	0.000	76.881	6.407	18.029	3.575	76.881	0.009	0.002	191.87	0.022	16.43	0.002
2016	0.058	0.048	0.055	0.040	77.188	0.000	77.188	6.432	18.101	3.589	77.188	0.009	0.002	228.22	0.026	35.18	0.004
2017	0.060	0.049	0.057	0.042	76.704	0.000	76.704	6.392	17.987	3.567	76.704	0.009	0.002	258.99	0.030	36.72	0.004
2018	0.062	0.051	0.059	0.044	76.222	0.000	76.222	6.352	17.874	3.544	76.222	0.009	0.002	289.75	0.033	38.26	0.004
2019	0.064	0.053	0.061	0.046	75.743	0.000	75.743	6.312	17.762	3.522	75.743	0.009	0.002	320.52	0.037	39.80	0.005
2020	0.065	0.055	0.064	0.048	75.267	0.000	75.267	6.272	17.650	3.500	75.267	0.009	0.002	351.29	0.040	41.34	0.005
2021	0.066	0.055	0.065	0.049	75.613	0.000	75.613	6.301	17.731	3.516	75.613	0.009	0.002	328.09	0.037	35.34	0.004
2022	0.067	0.056	0.066	0.049	75.960	0.000	75.960	6.330	17.813	3.532	75.960	0.009	0.002	304.90	0.035	29.34	0.003
2023	0.068	0.056	0.066	0.050	76.309	0.000	76.309	6.359	17.894	3.548	76.309	0.009	0.002	281.70	0.032	23.34	0.003
2024	0.068	0.057	0.067	0.051	76.660	0.000	76.660	6.388	17.977	3.565	76.660	0.009	0.002	258.50	0.030	17.35	0.002
2025	0.069	0.058	0.068	0.051	77.012	0.000	77.012	6.418	18.059	3.581	77.012	0.009	0.002	235.31	0.027	11.35	0.001
2026	0.070	0.058	0.069	0.052	77.365	0.000	77.365	6.447	18.142	3.597	77.365	0.009	0.002	212.11	0.024	5.35	0.001
2027	0.071	0.059	0.070	0.053	77.721	0.000	77.721	6.477	18.225	3.614	77.721	0.009	0.002	188.91	0.022	(0.65)	(0.000)
2028	0.071	0.059	0.071	0.054	78.078	0.000	78.078	6.506	18.309	3.631	78.078	0.009	0.002	165.72	0.019	(6.65)	(0.001)
2029	0.072	0.060	0.072	0.054	78.436	0.000	78.436	6.536	18.393	3.647	78.436	0.009	0.002	142.52	0.016	(12.64)	(0.001)
2030	0.073	0.061	0.073	0.055	78.796	0.000	78.796	6.566	18.478	3.664	78.796	0.009	0.002	119.32	0.014	(16.64)	(0.002)
2031	0.073	0.060	0.073	0.055	72.952	0.000	72.952	6.079	17.107	3.392	72.952	0.008	0.002	109.42	0.012	(18.43)	(0.002)
2032	0.073	0.060	0.073	0.055	67.541	0.000	67.541	5.628	15.838	3.141	67.541	0.008	0.002	99.52	0.011	(18.22)	(0.002)
2033	0.073	0.060	0.074	0.054	62.531	0.000	62.531	5.211	14.664	2.908	62.531	0.007	0.002	89.62	0.010	(18.01)	(0.002)
2034	0.073	0.060	0.074	0.054	57.893	0.000	57.893	4.824	13.576	2.692	57.893	0.007	0.002	79.72	0.009	(17.80)	(0.002)
2035	0.073	0.060	0.075	0.054	53.599	0.000	53.599	4.467	12.569	2.492	53.599	0.006	0.001	69.82	0.008	(17.59)	(0.002)
2036	0.073	0.060	0.075	0.054	49.623	0.000	49.623	4.135	11.637	2.307	49.623	0.006	0.001	59.92	0.007	(17.38)	(0.002)
2037	0.073	0.059	0.075	0.054	45.943	0.000	45.943	3.829	10.774	2.136	45.943	0.005	0.001	50.02	0.006	(17.17)	(0.002)
2038	0.073	0.059	0.076	0.053	42.535	0.000	42.535	3.545	9.974	1.978	42.535	0.005	0.001	40.12	0.005	(16.96)	(0.002)
2039	0.073	0.059	0.076	0.053	39.380	0.000	39.380	3.282	9.235	1.831	39.380	0.004	0.001	30.22	0.003	(16.75)	(0.002)
2040	0.073	0.059	0.076	0.053	36.459	0.000	36.459	3.038	8.550	1.695	36.459	0.004	0.001	20.32	0.002	(16.54)	(0.002)
Levelized[3]:																	
2005-2040	0.068	0.056	0.066	0.049	64.742	0.215	64.957	5.395	15.182	3.010	64.957	0.007	0.002	220.657	0.025	7.200	0.001
2006-2040	0.068	0.056	0.066	0.048	67.237	0.186	67.422	5.603	15.767	3.127	67.422	0.008	0.002	229.525	0.026	7.489	0.001
2006-2010	0.074	0.060	0.070	0.050	54.120	0.927	55.047	4.510	12.691	2.517	55.047	0.006	0.001	448.938	0.051	28.472	0.003
2006-2015	0.066	0.053	0.062	0.045	64.347	0.515	64.862	5.362	15.089	2.992	64.862	0.007	0.002	304.283	0.035	8.063	0.001
2006-2020	0.065	0.053	0.061	0.044	67.922	0.360	68.282	5.660	15.928	3.158	68.282	0.008	0.002	299.546	0.034	17.117	0.002

Exhibit A2-3. Electric Energy Avoided Costs by State (continued)

	Connecticut																
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	Annual Market Capacity Value[1]	Annual Out of Market Expense	Total Annual Capacity Value	Capacity Value of Load Response (of any month)	Available Capacity Payment of Load Response (Summer Season)	Available Capacity Payment of Load Response (Winter Season)	Available Capacity Payment of Energy Efficiency at Summer Coincident Peak	Load Response (at any month)	Energy Efficiency at Summer Coincident Peak	DRIPE 0.75% Capacity Price	DRIPE 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price	DRIPE LIGHT 0.75% Capacity Price
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-month	$/kW-season	$/kW-season	$/kW-yr	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kW-yr	$/kWh
Comment 1:	Values are avoided costs at the generation plus transmission level. DSM savings should be measured at the generator plus transmission level. (Load plus + distribution losses)				Reflects Capacity Price resulting from LICAP beginning in 2006	Recovery of costs for RMR including continuing required payments after LICAP initiation		Avoided Cost applicable to KW savings contributing as supply side credit, load savings plus reserve margin credit plus transmission and distribution losses to place at generator level			Avoided Cost applicable to KW savings at Summer Coincident Peak; load savings plus reserve margin credit plus transmission and distribution losses to place at generator level	Avoided cost expressed in $/kWh at 100% load factor		Incremental to Avoided Cost at Summer Coincident Peak	Expressed in $/kWh at 100% load factor	DRIPE 0.75% measured assuming 10% of supply resources transact in spot market	Expressed in $/kWh at 100% load factor
Comment 2					info	info	June/July/ August	Average for 1 month savings	Average for Summer Season	Average for Winter Season	June / July / August			DRIPE measured at 0.75% peak savings are across all of New England. Values		DRIPE LIGHT measured at 0.75% peak savings are across all of New England.	
Period:							3-5 pm		June, July, August	Jan-May, Sept-Dec	3-5 pm						
2005[2]	0.081	0.066	0.082	0.055	6.783	13.549	20.332	0.565	1.591	0.315	20.332	0.001	0.002	0.00	0.000	0.00	0.000
2006	0.094	0.075	0.095	0.064	48.378	3.865	52.243	4.031	11.345	2.250	52.243	0.006	0.006	305.26	0.035	156.87	0.018
2007	0.099	0.077	0.096	0.065	51.479	2.983	54.462	4.290	12.072	2.394	54.462	0.006	0.006	127.23	0.015	181.39	0.021
2008	0.080	0.063	0.076	0.053	65.040	0.908	65.949	5.420	15.252	3.024	65.949	0.007	0.008	111.60	0.013	157.35	0.018
2009	0.065	0.051	0.060	0.042	69.546	0.881	70.427	5.796	16.309	3.234	70.427	0.008	0.008	451.40	0.052	192.54	0.022
2010	0.056	0.043	0.052	0.036	72.357	0.836	73.194	6.030	16.968	3.365	73.194	0.008	0.008	373.73	0.043	180.60	0.021
2011	0.057	0.045	0.053	0.038	75.282	0.794	76.076	6.273	17.654	3.501	76.076	0.009	0.009	296.05	0.034	168.65	0.019
2012	0.058	0.046	0.054	0.039	78.325	0.753	79.078	6.527	18.367	3.642	79.078	0.009	0.009	218.38	0.025	156.71	0.018
2013	0.059	0.046	0.054	0.039	78.636	0.000	78.636	6.553	18.440	3.657	78.636	0.009	0.009	225.37	0.026	144.31	0.016
2014	0.059	0.047	0.055	0.039	78.948	0.000	78.948	6.579	18.513	3.671	78.948	0.009	0.009	232.37	0.027	131.91	0.015
2015	0.059	0.047	0.055	0.040	79.262	0.000	79.262	6.605	18.587	3.686	79.262	0.009	0.009	239.36	0.027	119.51	0.014
2016	0.060	0.047	0.055	0.040	79.577	0.000	79.577	6.631	18.661	3.700	79.577	0.009	0.009	246.36	0.028	107.11	0.012
2017	0.061	0.049	0.058	0.042	78.769	0.000	78.769	6.564	18.471	3.663	78.769	0.009	0.009	242.21	0.028	104.93	0.012
2018	0.063	0.051	0.060	0.043	77.968	0.000	77.968	6.497	18.284	3.626	77.968	0.009	0.009	238.06	0.027	102.74	0.012
2019	0.065	0.052	0.062	0.045	77.176	0.000	77.176	6.431	18.098	3.589	77.176	0.009	0.009	233.91	0.027	100.55	0.011
2020	0.067	0.054	0.065	0.047	76.392	0.000	76.392	6.366	17.914	3.552	76.392	0.009	0.009	229.77	0.026	98.36	0.011
2021	0.067	0.055	0.066	0.048	76.552	0.000	76.552	6.379	17.952	3.560	76.552	0.009	0.009	220.70	0.025	95.45	0.011
2022	0.068	0.055	0.066	0.049	76.713	0.000	76.713	6.393	17.989	3.567	76.713	0.009	0.009	211.64	0.024	92.54	0.011
2023	0.068	0.056	0.067	0.049	76.875	0.000	76.875	6.406	18.027	3.575	76.875	0.009	0.009	202.58	0.023	89.63	0.010
2024	0.069	0.056	0.068	0.050	77.036	0.000	77.036	6.420	18.065	3.582	77.036	0.009	0.009	193.51	0.022	86.72	0.010
2025	0.070	0.057	0.069	0.050	77.199	0.000	77.199	6.433	18.103	3.590	77.199	0.009	0.009	184.45	0.021	83.81	0.010
2026	0.070	0.058	0.069	0.051	77.361	0.000	77.361	6.447	18.141	3.597	77.361	0.009	0.009	175.39	0.020	80.90	0.009
2027	0.071	0.058	0.070	0.052	77.524	0.000	77.524	6.460	18.179	3.605	77.524	0.009	0.009	166.32	0.019	77.99	0.009
2028	0.072	0.059	0.071	0.052	77.687	0.000	77.687	6.474	18.218	3.612	77.687	0.009	0.009	157.26	0.018	75.08	0.009
2029	0.072	0.059	0.072	0.053	77.850	0.000	77.850	6.488	18.256	3.620	77.850	0.009	0.009	148.20	0.017	72.17	0.008
2030	0.073	0.060	0.073	0.054	78.014	0.000	78.014	6.501	18.294	3.628	78.014	0.009	0.009	139.13	0.016	69.28	0.008
2031	0.073	0.060	0.073	0.053	72.226	0.000	72.226	6.019	16.937	3.359	72.226	0.008	0.008	128.05	0.015	64.91	0.007
2032	0.073	0.060	0.073	0.053	66.868	0.000	66.868	5.572	15.680	3.109	66.868	0.008	0.008	116.95	0.013	60.55	0.007
2033	0.073	0.059	0.074	0.053	61.907	0.000	61.907	5.159	14.517	2.879	61.907	0.007	0.007	105.88	0.012	56.19	0.006
2034	0.073	0.059	0.074	0.053	57.314	0.000	57.314	4.776	13.440	2.665	57.314	0.007	0.007	94.80	0.011	51.84	0.006
2035	0.073	0.059	0.075	0.053	53.062	0.000	53.062	4.422	12.443	2.467	53.062	0.006	0.006	83.71	0.010	47.48	0.005
2036	0.073	0.059	0.075	0.053	49.125	0.000	49.125	4.094	11.520	2.284	49.125	0.006	0.006	72.63	0.008	43.13	0.005
2037	0.073	0.059	0.076	0.053	45.481	0.000	45.481	3.790	10.665	2.115	45.481	0.005	0.005	61.55	0.007	38.77	0.004
2038	0.073	0.059	0.076	0.053	42.106	0.000	42.106	3.509	9.874	1.958	42.106	0.005	0.005	50.46	0.006	34.42	0.004
2039	0.073	0.059	0.077	0.053	38.982	0.000	38.982	3.249	9.141	1.813	38.982	0.004	0.004	39.38	0.004	30.06	0.003
2040	0.073	0.058	0.077	0.053	36.090	0.000	36.090	3.008	8.463	1.678	36.090	0.004	0.004	28.30	0.003	25.70	0.003
Levelized[3]:																	
2005-2040	0.070	0.056	0.068	0.049	66.745	0.927	67.672	5.562	15.652	3.104	67.672	0.008	0.008	188.17	0.021	101.57	0.012
2006-2040	0.069	0.056	0.068	0.048	69.155	0.419	69.575	5.763	16.217	3.216	69.575	0.008	0.008	195.735	0.022	105.654	0.012
2006-2010	0.079	0.062	0.076	0.052	61.095	1.928	63.022	5.091	14.327	2.841	63.022	0.007	0.007	272.011	0.031	173.493	0.020
2006-2015	0.069	0.054	0.066	0.046	69.150	1.164	70.313	5.762	16.216	3.215	70.313	0.008	0.008	258.097	0.029	159.825	0.018
2006-2020	0.067	0.053	0.064	0.045	71.811	0.814	72.625	5.984	16.840	3.339	72.625	0.008	0.008	252.128	0.029	142.700	0.016